UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For The Quarterly Period Ended June 30, 2021

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ____________ to ____________

Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**64-0844345**
State or Other Jurisdiction of Incorporation or Organization	I.R.S. Employer Identification No.
One Briarlake Plaza 2000 W. Sam Houston Parkway S., Suite 2000 Houston, Texas	**77042**
Address of Principal Executive Offices	Zip Code

(281) 589-5200
Registrant's Telephone Number, Including Area Code

Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	CPE	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act:

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The Registrant had 46,290,613 shares of common stock outstanding as of July 30, 2021.

Table of Contents

GLOSSARY OF CERTAIN TERMS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their prescribed meanings when used in this report. As used in this document:

- **ASU**: accounting standards update.
- **Bbl**: barrel or barrels of oil or natural gas liquids.
- **Boe**: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of natural gas. The ratio of one barrel of oil or NGLs to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- **Boe/d**: Boe per day.
- **Btu**: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **Completion**: the process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- **Cushing**: an oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- **FASB**: Financial Accounting Standards Board.
- **GAAP**: Generally Accepted Accounting Principles in the United States.
- **Henry Hub**: a natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- **Horizontal drilling**: a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at an angle within a specified interval.
- **LOE**: lease operating expense.
- **MBbls**: thousand barrels of oil.
- **MBoe**: thousand Boe.
- **Mcf**: thousand cubic feet of natural gas.
- **MEH**: Magellan East Houston, a delivery point in Houston, Texas that serves as a benchmark for crude oil.
- **MMBoe**: million Boe.
- **MMBtu**: million Btu.
- **MMcf**: million cubic feet of natural gas.
- **NGL or NGLs**: natural gas liquids, such as ethane, propane, butane and natural gasoline that are extracted from natural gas production streams.
- **NYMEX**: New York Mercantile Exchange.
- **Oil**: includes crude oil and condensate.
- **OPEC**: Organization of Petroleum Exporting Countries.
- **Proved reserves**: Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

  The area of the reservoir considered as proved includes all of the following:

  a. The area identified by drilling and limited by fluid contacts, if any, and
  b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

  Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

  a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
  b. The project has been approved for development by all necessary parties and entities, including governmental entities.

  Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- **Realized price**: the cash market price less all expected quality, transportation and demand adjustments.
- **RSU**: restricted stock units.
- **SEC**: United States Securities and Exchange Commission.
- **Waha**: a delivery point in West Texas that serves as the benchmark for natural gas.
- **Working interest**: an operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
- **WTI**: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

With respect to information relating to our working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

Part I. Financial Information
Item 1. Financial Statements

Callon Petroleum Company
Consolidated Balance Sheets
(In thousands, except par and share amounts)
(Unaudited)

	June 30, 2021	December 31, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$3,800	$20,236
Accounts receivable, net	200,246	133,109
Fair value of derivatives	14,941	921
Other current assets	24,876	24,103
Total current assets	243,863	178,369
Oil and natural gas properties, full cost accounting method:		
Evaluated properties, net	2,517,783	2,355,710
Unevaluated properties	1,697,832	1,733,250
Total oil and natural gas properties, net	4,215,615	4,088,960
Other property and equipment, net	32,805	31,640
Deferred financing costs	20,670	23,643
Other assets, net	33,444	40,256
Total assets	$4,546,397	$4,362,868
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$419,434	$341,519
Fair value of derivatives	331,702	97,060
Other current liabilities	62,668	58,529
Total current liabilities	813,804	497,108
Long-term debt	2,865,154	2,969,264
Asset retirement obligations	57,546	57,209
Fair value of derivatives	8,204	88,046
Other long-term liabilities	44,401	40,239
Total liabilities	3,789,109	3,651,866
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value, 78,750,000 and 52,500,000 shares authorized; 46,288,813 and 39,758,817 shares outstanding, respectively	463	398
Capital in excess of par value	3,361,282	3,222,959
Accumulated deficit	(2,604,457)	(2,512,355)
Total stockholders' equity	757,288	711,002
Total liabilities and stockholders' equity	$4,546,397	$4,362,868

The accompanying notes are an integral part of these consolidated financial statements.

Callon Petroleum Company
Consolidated Statements of Operations
(In thousands, except per share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	**2020**	**2021**	**2020**
Operating Revenues:				
Oil	$333,442	$130,513	$600,487	$396,280
Natural gas	24,080	12,242	48,300	18,271
Natural gas liquids	36,625	14,479	65,982	32,602
Sales of purchased oil and gas	46,252	—	85,511	—
Total operating revenues	440,399	157,234	800,280	447,153
Operating Expenses:				
Lease operating	46,460	50,838	86,913	103,221
Production and ad valorem taxes	21,958	10,361	40,397	30,041
Gathering, transportation and processing	20,031	20,037	38,012	34,415
Cost of purchased oil and gas	49,249	—	90,166	—
Depreciation, depletion and amortization	83,128	138,930	154,115	270,393
General and administrative	11,065	10,024	27,864	18,349
Impairment of evaluated oil and gas properties	—	1,276,518	—	1,276,518
Merger and integration	—	8,067	—	23,897
Other operating	2,437	4,135	3,366	4,135
Total operating expenses	234,328	1,518,910	440,833	1,760,969
Income (Loss) From Operations	206,071	(1,361,676)	359,447	(1,313,816)
Other (Income) Expenses:				
Interest expense, net of capitalized amounts	24,634	22,682	49,050	43,160
(Gain) loss on derivative contracts	190,463	126,965	404,986	(125,004)
Other (income) expense	3,147	2,157	(1,088)	895
Total other (income) expense	218,244	151,804	452,948	(80,949)
Loss Before Income Taxes	(12,173)	(1,513,480)	(93,501)	(1,232,867)
Income tax benefit (expense)	478	(51,251)	1,399	(115,299)
Net Loss	($11,695)	($1,564,731)	($92,102)	($1,348,166)
Net Loss Per Common Share[1]:				
Basic	($0.25)	($39.41)	($2.07)	($33.97)
Diluted	($0.25)	($39.41)	($2.07)	($33.97)
Weighted Average Common Shares Outstanding[1]:				
Basic	46,267	39,707	44,439	39,687
Diluted	46,267	39,707	44,439	39,687

(1) All share and per share amounts have been retroactively adjusted for the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 - Stockholders' Equity" for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(In thousands)
(Unaudited)

	Common Stock Shares	Common Stock $	Capital in Excess of Par	Accumulated Deficit	Total Stockholders' Equity
Balance at December 31, 2020	39,759	$398	$3,222,959	($2,512,355)	$711,002
Net loss	—	—	—	(80,407)	(80,407)
Restricted stock	13	—	2,609	—	2,609
Warrant exercises	6,385	64	134,754	—	134,818
Balance at March 31, 2021	46,157	$462	$3,360,322	($2,592,762)	$768,022
Net loss	—	—	—	(11,695)	(11,695)
Restricted stock	132	1	960	—	961
Balance at June 30, 2021	46,289	$463	$3,361,282	($2,604,457)	$757,288

	Common Stock Shares (1)	Common Stock $	Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance at December 31, 2019	39,659	$3,966	$3,198,076	$21,266	$3,223,308
Net income	—	—	—	216,565	216,565
Restricted stock	14	1	3,141	—	3,142
Other	—	—	(112)	—	(112)
Balance at March 31, 2020	39,673	$3,967	$3,201,105	$237,831	$3,442,903
Net loss	—	—	—	(1,564,731)	(1,564,731)
Restricted stock	66	7	3,205	—	3,212
Balance at June 30, 2020	39,739	$3,974	$3,204,310	($1,326,900)	$1,881,384

(1) All share amounts have been retroactively adjusted for the Company's 1-for-10 reverse stock split effective August 7, 2020. See " Note 11 - Stockholders' Equity" for additional information.

The accompanying notes are an integral part of these consolidated financial statements.

Callon Petroleum Company
Consolidated Statements of Cash Flows
(In thousands)
(Unaudited)

	Six Months Ended June 30,	
Cash flows from operating activities:	**2021**	**2020**
Net loss	($92,102)	($1,348,166)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	154,115	270,393
Impairment of evaluated oil and gas properties	—	1,276,518
Amortization of non-cash debt related items, net	4,508	1,145
Deferred income tax expense	—	115,299
(Gain) loss on derivative contracts	404,986	(125,004)
Cash received (paid) for commodity derivative settlements, net	(127,571)	101,301
Non-cash expense (benefit) related to share-based awards	12,887	(211)
Other, net	4,511	3,656
Changes in current assets and liabilities:		
Accounts receivable	(67,357)	113,040
Other current assets	(7,423)	(4,348)
Accounts payable and accrued liabilities	26,714	(114,127)
Net cash provided by operating activities	313,268	289,496
Cash flows from investing activities:		
Capital expenditures	(251,003)	(418,688)
Acquisition of oil and gas properties	(2,215)	(11,881)
Proceeds from sale of assets	31,611	10,079
Cash paid for settlements of contingent consideration arrangements, net	—	(40,000)
Other, net	4,220	6,834
Net cash used in investing activities	(217,387)	(453,656)
Cash flows from financing activities:		
Borrowings on Credit Facility	736,500	4,775,500
Payments on Credit Facility	(846,500)	(4,610,500)
Payment of deferred financing and debt exchange costs	—	(6,011)
Tax withholdings related to restricted stock units	(2,280)	(388)
Other, net	(37)	(282)
Net cash provided by (used in) financing activities	(112,317)	158,319
Net change in cash and cash equivalents	(16,436)	(5,841)
Balance, beginning of period	20,236	13,341
Balance, end of period	$3,800	$7,500

The accompanying notes are an integral part of these consolidated financial statements.

Index to the Notes to the Consolidated Financial Statements

Note 1 - Description of Business and Basis of Presentation

Description of Business

Callon Petroleum Company is an independent oil and natural gas company focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

The Company's activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas, as well as the Eagle Ford in South Texas. The Company's primary operations in the Permian reflect a high-return, oil-weighted drilling inventory with multiple prospective horizontal development intervals and are complemented by a well-established and repeatable cash flow-generating business in the Eagle Ford.

Basis of Presentation

The accompanying unaudited interim consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances. These financial statements have been prepared pursuant to the rules and regulations of the SEC and therefore do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. In the opinion of management, these financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim financial position, results of operations and cash flows. However, the results of operations for the periods presented are not necessarily indicative of the results of operations that may be expected for the full year. Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications did not have a material impact on prior period financial statements.

Significant Accounting Policies

The Company's significant accounting policies are described in "Note 2 - Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in its Annual Report on Form 10-K for the year ended December 31, 2020 ("2020 Annual Report") and are supplemented by the notes included in this Quarterly Report on Form 10-Q. The financial statements and related notes included in this report should be read in conjunction with the Company's 2020 Annual Report.

Recently Adopted Accounting Standards

Income Taxes. In December 2019, the FASB released ASU No. 2019-12 ("ASU 2019-12"), Income Taxes (Topic 740) – Simplifying the Accounting for Income Taxes, which removes certain exceptions for recognizing deferred taxes for investments, performing intraperiod allocation and calculating income taxes in interim periods. The ASU also adds guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. The amended standard is effective for fiscal years beginning after December 15, 2020, with early adoption permitted. The Company adopted ASU 2019-12 on January 1, 2021. The adoption of ASU 2019-12 did not have a material impact to the Company's consolidated financial statements or disclosures.

Recently Issued Accounting Pronouncements

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("ASU 2020-04") followed by ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope ("ASU 2021-01"), issued in January 2021 to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. Generally, the guidance is to be applied as of any date from the beginning of an interim period that includes or is subsequent to March 12, 2020, or prospectively from a date within an interim period that includes or is subsequent to March 12, 2020, up to the date that the financial statements are available to be issued. ASU 2020-04 and ASU 2021-01 are effective for all entities through December 31, 2022. As of June 30, 2021, the Company has not elected to use the optional guidance and continues to evaluate the options provided by ASU 2020-04 and ASU 2021-01. Please refer to "Note 6 – Borrowings" for discussion of the use of the adjusted LIBO rate in connection with borrowings under the Company’s senior secured revolving credit facility.

In August 2020, the FASB issued ASU No. 2020-06, Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity’s Own Equity (Subtopic 815-40) (“ASU 2020-06”). ASU 2020-06 was issued to reduce the complexity associated with accounting for certain financial instruments with characteristics of liabilities and equity. The guidance is to be applied using either a modified retrospective or a fully retrospective method. ASU 2020-06 is effective for fiscal years beginning after December 15, 2021, with early adoption permitted. As of June 30, 2021, the Company has not elected to early adopt and is evaluating the impact on the Company’s accompanying consolidated financial statements and related disclosures.

Subsequent Events

The Company evaluates subsequent events through the date the financial statements are issued. See “Note 15 - Subsequent Events” for further discussion.

Note 2 - Revenue Recognition

Revenue from contracts with customers

The Company recognizes oil, natural gas, and NGL production revenue at the point in time when control of the product transfers to the purchaser, which differs depending on the applicable contractual terms. Transfer of control also drives the presentation of gathering, transportation and processing in the consolidated statements of operations. See “Note 3 - Revenue Recognition” of the Notes to Consolidated Financial Statements in the 2020 Annual Report for more information regarding the types of contracts under which oil, natural gas, and NGL production revenue is generated.

Accounts receivable from revenues from contracts with customers

Net accounts receivable include amounts billed and currently due from revenues from contracts with customers of our oil and natural gas production, which had a balance at June 30, 2021 and December 31, 2020 of $148.7 million and $100.3 million, respectively, and are presented in “Accounts receivable, net” in the consolidated balance sheets.

Transaction price allocated to remaining performance obligations

For the Company’s product sales that have a contract term greater than one year, it has utilized the practical expedient in Accounting Standards Codification 606-10-50-14, which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation, therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant.

Note 3 - Acquisitions and Divestitures

Non-Core Asset Divestitures

During the second quarter of 2021, the Company completed its divestitures of certain non-core assets in the Delaware Basin for aggregate net cash proceeds of $30.7 million, subject to post-closing adjustments. The divestitures were primarily comprised of natural gas producing properties in the Western Delaware Basin as well as a small undeveloped acreage position. The net proceeds were recognized as a reduction of evaluated oil and gas properties with no gain or loss recognized.

Note 4 - Property and Equipment, Net

As of June 30, 2021 and December 31, 2020, total property and equipment, net consisted of the following:

	June 30, 2021	December 31, 2020
Oil and natural gas properties, full cost accounting method	(In thousands)	
Evaluated properties	$8,206,124	$7,894,513
Accumulated depreciation, depletion, amortization and impairments	(5,688,341)	(5,538,803)
Evaluated properties, net	2,517,783	2,355,710
Unevaluated properties		
Unevaluated leasehold and seismic costs	1,462,154	1,532,304
Capitalized interest	235,678	200,946
Total unevaluated properties	1,697,832	1,733,250
Total oil and natural gas properties, net	$4,215,615	$4,088,960
Other property and equipment	$62,258	$60,287
Accumulated depreciation	(29,453)	(28,647)
Other property and equipment, net	$32,805	$31,640

The Company capitalized internal costs of employee compensation and benefits, including share-based compensation, directly associated with acquisition, exploration and development activities totaling $12.1 million and $8.9 million for the three months ended June 30, 2021 and 2020, respectively, and $23.3 million and $16.4 million for the six months ended June 30, 2021 and 2020, respectively.

The Company capitalized interest costs to unproved properties totaling $23.9 million and $20.9 million for the three months ended June 30, 2021 and 2020, respectively, and $47.9 million and $44.9 million for the six months ended June 30, 2021 and 2020, respectively.

Impairment of Evaluated Oil and Gas Properties

For the three and six months ended June 30, 2021, the capitalized costs of oil and gas properties did not exceed the cost center ceiling. As a result, the Company did not recognize an impairment in the carrying value of evaluated oil and gas properties for the three and six months ended June 30, 2021.

Primarily due to declines in the average realized prices for sales of oil on the first calendar day of each month during the trailing 12-month period ("12-Month Average Realized Price") prior to June 30, 2020, the capitalized costs of oil and gas properties exceeded the cost center ceiling resulting in an impairment in the carrying value of evaluated oil and gas properties for the three and six months ended June 30, 2020.

Details of the 12-Month Average Realized Price of crude oil for the three and six months ended June 30, 2021 and 2020 are summarized in the table below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
Impairment of evaluated oil and gas properties (in thousands)	$—	$1,276,518	$—	$1,276,518
Beginning of period 12-Month Average Realized Price ($/Bbl)	$37.51	$54.63	$37.44	$53.90
End of period 12-Month Average Realized Price ($/Bbl)	$48.06	$45.87	$48.06	$45.87
Percent increase (decrease) in 12-Month Average Realized Price	28 %	(16 %)	28 %	(15 %)

Note 5 - Earnings Per Share

Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the potential dilutive impact of non-vested restricted shares and unexercised warrants outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. For the three and six months ended June 30, 2021 and 2020, the Company reported a net loss. As a result, the calculation of diluted weighted average common shares outstanding excluded all potentially dilutive common shares outstanding.

The following table sets forth the computation of basic and diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(In thousands, except per share amounts)			
Net Loss	($11,695)	($1,564,731)	($92,102)	($1,348,166)
Basic weighted average common shares outstanding(1)	46,267	39,707	44,439	39,687
Dilutive impact of restricted stock (1)	—	—	—	—
Dilutive impact of warrants (1)	—	—	—	—
Diluted weighted average common shares outstanding(1)	46,267	39,707	44,439	39,687
Net Loss Per Common Share(1)				
Basic	($0.25)	($39.41)	($2.07)	($33.97)
Diluted	($0.25)	($39.41)	($2.07)	($33.97)
Restricted stock (1)(2)	140	432	882	424
Warrants (1)(2)	1,066	481	3,433	481

(1) Shares and per share data have been retroactively adjusted to reflect the Company's 1-for-10 reverse stock split effective August 7, 2020. See "Note 11 - Stockholders' Equity" for additional information.
(2) Shares excluded from the diluted earnings per share calculation as their effect would be anti-dilutive.

Note 6 - Borrowings

The Company's borrowings consisted of the following:

	June 30, 2021	December 31, 2020
	(In thousands)	
Senior Secured Revolving Credit Facility due 2024	$875,000	$985,000
9.00% Second Lien Senior Secured Notes due 2025	516,659	516,659
6.25% Senior Notes due 2023	542,720	542,720
6.125% Senior Notes due 2024	460,241	460,241
8.25% Senior Notes due 2025	187,238	187,238
6.375% Senior Notes due 2026	320,783	320,783
Total principal outstanding	2,902,641	3,012,641
Unamortized discount on Second Lien Notes	(36,241)	(41,820)
Unamortized premium on 6.25% Senior Notes	2,454	2,917
Unamortized premium on 6.125% Senior Notes	2,805	3,236
Unamortized premium on 8.25% Senior Notes	2,859	3,240
Unamortized deferred financing costs for Second Lien Notes	(3,399)	(3,931)
Unamortized deferred financing costs for Senior Notes	(5,965)	(7,019)
Total carrying value of borrowings (1)	$2,865,154	$2,969,264

(1) Excludes unamortized deferred financing costs related to the Company's senior secured revolving credit facility of $ 20.7 million and $ 23.6 million as of June 30, 2021 and December 31, 2020, respectively, which are classified in "Deferred financing costs" in the consolidated balance sheets.

Senior secured revolving credit facility

The Company has a senior secured revolving credit facility with a syndicate of lenders (the "Credit Facility") that, as of June 30, 2021, had a borrowing base and elected commitment amount of $1.6 billion, with borrowings outstanding of $875.0 million at a weighted-average interest rate of2.61%, and letters of credit outstanding of $24.0 million. The credit agreement governing the Credit Facility provides for interest-only payments until December 20, 2024 (subject to springing maturity dates of (i) January 14, 2023 if the 6.25% Senior Notes due 2023 (the "6.25% Senior Notes") are outstanding at such time (and which were retired in full on July 21, 2021), (ii) July 2, 2024 if the 6.125% Senior Notes due 2024 (the "6.125% Senior Notes") are outstanding at such time, and (iii) if the9.00% Second Lien Senior Secured Notes due 2025 (the "Second Lien Notes") are outstanding at such time, the date which is 182 days prior to the maturity of any of the6.25% Senior Notes or the 6.125% Senior Notes, in each case, to the extent a principal amount of more than $100.0 million with respect to each such issuance is outstanding as of such date), when the credit agreement matures and any outstanding borrowings are due. The borrowing base under the credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties.

The capitalized terms which are not defined in this description of the Credit Facility shall have the meaning given to such terms in the credit agreement.

On May 3, 2021, the Company entered into the fourth amendment to its credit agreement governing the Credit Facility. The amendment, among other things, (a) reaffirmed the borrowing base and the elected commitment amount of $1.6 billion as a result of the spring 2021 scheduled redetermination; and (b) permits the prepayment, repurchase or redemption of Junior Debt (as defined in the credit agreement governing the Credit Facility), which includes the Senior Unsecured Notes (as defined below) and the Second Lien Notes, in an aggregate amount not to exceed $100.0 million, commencing April 1, 2021, if certain liquidity and free cash flow thresholds are met.

Borrowings outstanding under the credit agreement bear interest at the Company's option at either (i) a base rate for a base rate loan plus a margin between 1.00% to 2.00%, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus a margin between 2.00% to 3.00%. The Company also incurs commitment fees at rates ranging between 0.375% to 0.500% on the unused portion of lender commitments, which are included in "Interest expense, net of capitalized amounts" in the consolidated statements of operations.

Restrictive covenants

The Company's credit agreement contains certain covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios.

Under the credit agreement, the Company must maintain the following financial covenants determined as of the last day of the quarter: (1) a Secured Leverage Ratio of no more than 3.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. The Company was in compliance with these covenants at June 30, 2021.

The credit agreement and the indentures governing the Company's 6.25% Senior Notes, 6.125% Senior Notes, 8.25% Senior Notes due 2025, and 6.375% Senior Notes due 2026 (together the "Senior Unsecured Notes") also place restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company's common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The credit agreement and indentures are subject to customary events of default. If an event of default occurs and is continuing, the holders or lenders may elect to accelerate amounts due (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

Note 7 - Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil, natural gas and NGL prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil, natural gas and NGL production. The Company utilizes a mix of collars, swaps, and put and call options to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The Company typically has numerous commodity derivative instruments outstanding with a counterparty that were executed at various dates, for various contract types, commodities and time periods. This often results in both commodity derivative asset and liability positions with that counterparty. The Company nets its commodity derivative instrument fair values executed with the same counterparty to a single asset or liability pursuant to International Swap Dealers Association Master Agreements ("ISDA Agreements"), which provide for net settlement over the term of the contract and in the event of default or termination of the contract. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer or terminate the arrangement.

As of June 30, 2021, the Company has outstanding commodity derivative instruments with fifteen counterparties to minimize its credit exposure to any individual counterparty. All of the counterparties to the Company's commodity derivative instruments are also lenders under the Company's credit agreement. Therefore, each of the Company's counterparties allow the Company to satisfy any need for margin obligations associated with commodity derivative instruments where the Company is in a net liability position with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting.

Because each of the Company's counterparties has an investment grade credit rating, the Company believes it does not have significant credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its commodity derivative instruments. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of each counterparty.

While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument. See "Note 8 - Fair Value Measurements" for further discussion.

Financial statement presentation and settlements

Settlements of the Company's commodity derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a benchmark price, such as the NYMEX price. To determine the fair value of the Company's derivative instruments, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See "Note 8 - Fair Value Measurements" for additional information regarding fair value.

Contingent consideration arrangements

Ranger Divestiture. In the second quarter of 2019, the Company completed its divestiture of certain non-core assets in the southern Midland Basin (the "Ranger Divestiture"). The Company's Ranger Divestiture provided for potential contingent consideration to be received by the Company if commodity prices exceed specified thresholds. See "Note 8 - Fair Value Measurements" for further discussion. This contingent consideration arrangement is summarized in the table below (in thousands except for per Bbl amounts):

	Year	Threshold (1)	Contingent Receipt - Annual	Threshold (1)	Contingent Receipt - Annual	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Remaining Contingent Receipt - Aggregate Limit
Remaining Potential Settlement	2021	Greater than $60/Bbl, less than $65/Bbl	$9,000	Equal to or greater than $65/Bbl	$20,833	(2)	(2)	$20,833

(1) The price used to determine whether the specified thresholds have been met is the average of the final monthly settlements for each month during each annual period end for NYMEX Light Sweet Crude Oil Futures, as reported by the CME Group.

(2) Cash received for settlements of contingent consideration arrangements are classified as cash flows from financing activities up to the divestiture date fair value with any excess classified as cash flows from operating activities. If either of the commodity price thresholds is reached in 2021, $8.5 million of the contingent receipt will be presented in cash flows from financing activities with the remainder presented in cash flows from operating activities in the first quarter of 2022.

As a result of the acquisition of Carrizo Oil & Gas, Inc. ("Carrizo") in late 2019 (the "Carrizo Acquisition"), the Company assumed all contingent consideration arrangements previously entered into by Carrizo. Only one of the contingent consideration arrangements remains and is summarized below:

Contingent ExL Consideration

	Year	Threshold (1)	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Contingent Payment - Annual	Remaining Contingent Payments - Aggregate Limit
					(In thousands)	
Remaining Potential Settlement	2021	$50.00	(2)	(2)	($25,000)	($25,000)

(1) The price used to determine whether the specified threshold for the year has been met is the average daily settlement price of the front month NYMEX WTI futures contract as published by the CME Group.

(2) Cash paid for settlements of contingent consideration arrangements are classified as cash flows from investing activities up to the acquisition date fair value with any excess classified as cash flows from operating activities. If the commodity price threshold is reached in 2021, $19.2 million of the contingent payment will be presented in cash flows from investing activities with the remainder presented in cash flows from operating activities in the first quarter of 2022.

Warrants

On September 30, 2020, the Company issued $300.0 million in aggregate principal amount of its Second Lien Notes and warrants for7.3 million shares of the Company's common stock exercisable only on a net share settlement basis (the "September 2020 Warrants"). The Company determined that the September 2020 Warrants were required to be accounted for as a derivative instrument. The Company recorded the September 2020 Warrants as a liability on its consolidated balance sheet measured at fair value as a component of "Fair value of derivatives" with gains and losses as a result of changes in the fair value of the September 2020 Warrants recorded as "(Gain) loss on derivative contracts" in the consolidated statements of operations in the period in which the changes occur. See "Note 8 - Fair Value Measurements" for additional details.

In February 2021, holders of the September 2020 Warrants provided notice and exercised all of their outstanding warrants. As a result of this exercise, the Company issued 5.6 million shares of its common stock in exchange for all of the outstanding September 2020 Warrants. The exercise of the September 2020 Warrants resulted in settlement of the associated derivative liability, which was $134.8 million at the time of exercise, and the fair value of the September 2020 Warrants at exercise, less the par value of the shares of common stock issued in the exercise, was reclassified to "Capital in excess of par value" in the consolidated balance sheets.

Derivatives not designated as hedging instruments

The Company records its derivative instruments at fair value in the consolidated balance sheets and records changes in fair value as "(Gain) loss on derivative contracts" in the consolidated statements of operations. Settlements are also recorded as a gain or loss on derivative contracts in the consolidated statements of operations. As previously discussed, the Company's commodity derivative contracts are subject to master netting arrangements. The Company's policy is to present the fair value of derivative contracts on a net basis in the consolidated balance sheets. The following presents the impact of this presentation to the Company's recognized assets and liabilities for the periods indicated:

	As of June 30, 2021		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
		(In thousands)	
Assets			
Commodity derivative instruments	$79,820	($79,564)	$256
Contingent consideration arrangements	14,685	—	14,685
Fair value of derivatives - current	$94,505	($79,564)	$14,941
Commodity derivative instruments	$5,850	($5,850)	$—
Contingent consideration arrangements	—	—	—
Other assets, net	$5,850	($5,850)	$—
Liabilities			
Commodity derivative instruments [1]	($387,162)	$79,564	($307,598)
Contingent consideration arrangements	(24,104)	—	(24,104)
Fair value of derivatives - current	($411,266)	$79,564	($331,702)
Commodity derivative instruments	($14,054)	$5,850	($8,204)
Contingent consideration arrangements	—	—	—
Fair value of derivatives - non-current	($14,054)	$5,850	($8,204)

(1) Includes approximately $8.3 million of deferred premiums, which the Company will pay as the applicable contracts settle.

	As of December 31, 2020		
	Presented without Effects of Netting	Effects of Netting	As Presented with Effects of Netting
	(In thousands)		
sets			
mmodity derivative instruments	$21,156	($20,235)	$921
ntingent consideration arrangements	—	—	—
'air value of derivatives - current	$21,156	($20,235)	$921
mmodity derivative instruments	$—	$—	$—
ntingent consideration arrangements	1,816	—	1,816
)ther assets, net	$1,816	$—	$1,816
ıbilities			
mmodity derivative instruments [1]	($117,295)	$20,235	($97,060)
ntingent consideration arrangements	—	—	—
'air value of derivatives - current	($117,295)	$20,235	($97,060)
mmodity derivative instruments	$—	$—	$—
ntingent consideration arrangements	(8,618)	—	(8,618)
ɔtember 2020 Warrants liability	(79,428)	—	(79,428)
'air value of derivatives - non-current	($88,046)	$—	($88,046)

(1) Includes approximately $11.2 million of deferred premiums, which the Company will pay as the applicable contracts settle.

The components of "(Gain) loss on derivative contracts" are as follows for the respective periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(In thousands)			
(Gain) loss on oil derivatives	$177,033	$122,369	$326,594	($134,954)
(Gain) loss on natural gas derivatives	12,816	4,695	15,513	11,524
(Gain) loss on NGL derivatives	3,734	(4)	4,872	(4)
(Gain) loss on contingent consideration arrangements	(3,120)	(95)	2,617	(1,570)
(Gain) loss on September 2020 Warrants liability	—	—	55,390	—
(Gain) loss on derivative contracts	$190,463	$126,965	$404,986	($125,004)

The components of "Cash received (paid) for commodity derivative settlements, net" and "Cash paid for settlements of contingent consideration arrangements, net" are as follows for the respective periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(In thousands)			
Cash flows from operating activities				
Cash received (paid) on oil derivatives	($82,413)	$100,470	($122,360)	$98,693
Cash received (paid) on natural gas derivatives	(1,906)	(1,782)	(3,275)	2,608
Cash received (paid) on NGL derivatives	(1,090)	—	(1,936)	—
Cash received (paid) for commodity derivative settlements, net	($85,409)	$98,688	($127,571)	$101,301
Cash flows from investing activities				
Cash paid for settlements of contingent consideration arrangements, net	$—	$—	$—	($40,000)

Derivative positions

Listed in the tables below are the outstanding oil, natural gas and NGL derivative contracts as of June 30, 2021:

Oil contracts (WTI)	For the Remainder of 2021	For the Full Year of 2022	For the Full Year of 2023
Swap contracts			
Total volume (Bbls)	1,104,000	1,372,500	—
Weighted average price per Bbl	$42.10	$60.00	$—
Collar contracts			
Total volume (Bbls)	5,522,775	3,725,000	—
Weighted average price per Bbl			
Ceiling (short call)	$49.16	$64.84	$—
Floor (long put)	$40.71	$52.66	$—
Short call contracts			
Total volume (Bbls)	2,432,480 (1)	—	—
Weighted average price per Bbl	$63.62	$—	$—
Short call swaption contracts			
Total volume (Bbls)	—	1,825,000 (2)	1,825,000 (2)
Weighted average price per Bbl	$—	$52.18	$72.00
Oil contracts (Brent ICE)			
Swap contracts			
Total volume (Bbls)	— (3)	—	—
Weighted average price per Bbl	$—	$—	$—
Collar contracts			
Total volume (Bbls)	368,000	—	—
Weighted average price per Bbl			
Ceiling (short call)	$50.00	$—	$—
Floor (long put)	$45.00	$—	$—
Oil contracts (Midland basis differential)			
Swap contracts			
Total volume (Bbls)	1,504,400	—	—
Weighted average price per Bbl	$0.25	$—	$—
Oil contracts (Argus Houston MEH)			
Collar contracts			
Total volume (Bbls)	—	452,500	—
Weighted average price per Bbl			
Ceiling (short call)	$—	$63.15	$—
Floor (long put)	$—	$51.25	$—

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.
(2) The 2022 and 2023 short call swaption contracts have exercise expiration dates of December 31, 2021 and December 30, 2022, respectively.
(3) In February 2021, the Company entered into certain offsetting ICE Brent swaps to reduce its exposure to rising oil prices. Those offsetting swaps resulted in a locked-in loss of approximately $ 2.9 million, of which $1.6 million will be settled in the third quarter of 2021 with the remaining $ 1.3 million to be settled in the fourth quarter of 2021.

Natural gas contracts (Henry Hub)	For the Remainder of 2021	For the Full Year of 2022
Swap contracts		
Total volume (MMBtu)	7,301,000	2,140,000
Weighted average price per MMBtu	$2.61	$2.65
Collar contracts		
Total volume (MMBtu)	3,680,000	3,600,000
Weighted average price per MMBtu		
Ceiling (short call)	$2.80	$3.75
Floor (long put)	$2.50	$2.83
Short call contracts		
Total volume (MMBtu)	3,680,000 (1)	—
Weighted average price per MMBtu	$3.09	$—
Natural gas contracts (Waha basis differential)		
Swap contracts		
Total volume (MMBtu)	8,280,000	5,475,000
Weighted average price per MMBtu	($0.42)	($0.21)

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

NGL contracts (OPIS Mont Belvieu Purity Ethane)	For the Remainder of 2021	For the Full Year of 2022
Swap contracts		
Total volume (Bbls)	920,000	—
Weighted average price per Bbl	$7.62	$—

Note 8 - Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair value of financial instruments

Cash, cash equivalents, and restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The carrying amount of borrowings outstanding under the Credit Facility approximates fair value as the borrowings bear interest at variable rates and are reflective of market rates. The following table presents the principal amounts of the Company's Second Lien Notes and Senior Unsecured Notes with the fair values measured using quoted secondary market trading prices which are designated as Level 2 within the valuation hierarchy. See "Note 6 - Borrowings" for further discussion.

	June 30, 2021		December 31, 2020	
	Principal Amount	Fair Value	Principal Amount	Fair Value
	(In thousands)			
Second Lien Notes	$516,659	$561,867	$516,659	$470,160
6.25% Senior Notes	542,720	542,720	542,720	344,627
6.125% Senior Notes	460,241	444,133	460,241	260,036
8.25% Senior Notes	187,238	184,429	187,238	100,172
6.375% Senior Notes	320,783	303,140	320,783	161,995
Total	$2,027,641	$2,036,289	$2,027,641	$1,336,990

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis in the consolidated balance sheets. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using a third-party income approach valuation model that utilizes market-corroborated inputs that are observable over the term of the commodity derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for commodity derivative assets and an estimate of the Company's default risk for commodity derivative liabilities. As the inputs in the model are substantially observable over the term of the commodity derivative contract and there is a wide availability of quoted market prices for similar commodity derivative contracts, the Company designates its commodity derivative instruments as Level 2 within the fair value hierarchy. See "Note 7 - Derivative Instruments and Hedging Activities" for further discussion.

Contingent consideration arrangements - embedded derivative financial instruments. The embedded options within the contingent consideration arrangements are considered financial instruments under ASC 815. The Company engages a third-party valuation specialist using an option pricing model approach to measure the fair value of the embedded options on a recurring basis. The valuation includes significant inputs such as forward oil price curves, time to expiration, and implied volatility. The model provides for the probability that the specified pricing thresholds would be met for each settlement period, estimates undiscounted payouts, and risk adjusts for the discount rates inclusive of adjustments for each of the counterparty's credit quality. As these inputs are substantially observable for the full term of the contingent consideration arrangements, the inputs are considered Level 2 inputs within the fair value hierarchy. See "Note 7 - Derivative Instruments and Hedging Activities" for further discussion.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis as of June 30, 2021 and December 31, 2020:

	June 30, 2021		
	Level 1	**Level 2**	**Level 3**
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$256	$—
Contingent consideration arrangements	—	14,685	—
Liabilities			
Commodity derivative instruments (1)	—	(315,802)	—
Contingent consideration arrangements	—	(24,104)	—
Total net assets (liabilities)	$—	($324,965)	$—

	December 31, 2020		
	Level 1	**Level 2**	**Level 3**
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$921	$—
Contingent consideration arrangements	—	1,816	—
Liabilities			
Commodity derivative instruments (2)	—	(97,060)	—
Contingent consideration arrangements	—	(8,618)	—
September 2020 Warrants	—	—	(79,428)
Total net assets (liabilities)	$—	($102,941)	($79,428)

(1) Includes approximately $8.3 million of deferred premiums which the Company will pay as the applicable contracts settle.
(2) Includes approximately $11.2 million of deferred premiums which the Company will pay as the applicable contracts settle.

September 2020 Warrants. The fair value of the September 2020 Warrants was calculated using a Black Scholes-Merton option pricing model. As historical volatility is a significant input into the model, the September 2020 Warrants were designated as Level 3 within the valuation hierarchy.

In February 2021, holders of the September 2020 Warrants provided notice and exercised all of their outstanding warrants. The exercise of the September 2020 Warrants resulted in settlement of the associated derivative liability of $134.8 million. See "Note 7 - Derivative Instruments and Hedging Activities" for additional details.

The following table presents a reconciliation of the change in the fair value of the liability related to the September 2020 Warrants, which was designated as Level 3 within the valuation hierarchy, for the six months ended June 30, 2021.

	Six Months Ended June 30, 2021
	(In thousands)
Beginning of period	$79,428
(Gain) loss on changes in fair value[(1)]	55,390
Transfers into (out of) Level 3	(134,818)
End of period	$—

(1) Included in "(Gain) loss on derivative contracts" in the consolidated statements of operations.

Assets and liabilities measured at fair value on a nonrecurring basis

Asset retirement obligations. The Company measures the fair value of asset retirement obligations as of the date a well begins drilling or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 within the valuation hierarchy. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities, restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates.

Note 9 - Income Taxes

The Company provides for income taxes at the statutory rate of21%. Reported income tax benefit (expense) differs from the amount of income tax benefit (expense) that would result from applying domestic federal statutory tax rates to pretax income (loss). These differences primarily relate to non-deductible executive compensation expenses, restricted stock windfalls, changes in valuation allowances, and state income taxes.

For the three months ended June 30, 2021, and 2020, the Company's effective income tax rates were4% and 3%, respectively. The primary differences between the effective tax rates for the three months ended June 30, 2021 and 2020 and the statutory rate resulted from the valuation allowance recorded against the Company's net deferred tax assets beginning in the second quarter of 2020 and the effect of state income taxes.

For the six months ended June 30, 2021 and 2020, the Company's effective income tax rates were1% and 9%, respectively. The primary differences between the effective tax rates for the six months ended June 30, 2021 and 2020 and the statutory rate resulted from the valuation allowance recorded against the Company's net deferred tax assets beginning in the second quarter of 2020 and the effect of state income taxes.

Deferred Tax Asset Valuation Allowance

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's net deferred tax assets will be utilized prior to their expiration. A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at June 30, 2021, driven primarily by the impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the fourth quarter of 2020. This limits the ability to consider other subjective evidence such as the Company's potential for future growth. Since the second quarter of 2020, based on the evaluation of the evidence available, the Company concluded that it is more likely than not that the net deferred tax assets will not be realized. As a result, the Company has recorded a valuation allowance, reducing the net deferred tax assets as of June 30, 2021 to zero.

The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until the Company can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more future potential transactions. The valuation allowance does not preclude the Company from utilizing the tax attributes if the Company recognizes taxable income. As long as the Company continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company will have no significant deferred income tax expense or benefit.

Note 10 - Share-Based Compensation

All share and per share numbers included in this footnote have been adjusted for the reverse stock split. See "Note 11 - Stockholders' Equity" for discussion of the reverse stock split and reduction in authorized shares.

RSU Equity Awards

The following table summarizes activity for restricted stock units that may be settled in common stock ("RSU Equity Awards") for the three and six months ended June 30, 2021 and 2020:

	Three Months Ended June 30,			
	2021		2020	
	RSU Equity Awards (in thousands)	Weighted Average Grant Date Fair Value	RSU Equity Awards (in thousands)	Weighted Average Grant Date Fair Value
Unvested, beginning of the period	1,210	$36.02	485	$69.50
Granted (1)	66	$38.86	324	$12.62
Vested (2)	(184)	$35.68	(90)	$100.57
Forfeited	(57)	$42.83	—	$—
Unvested, end of the period	1,035	$35.88	719	$39.99

	Six Months Ended June 30,			
	2021		2020	
	RSU Equity Awards (in thousands)	Weighted Average Grant Date Fair Value	RSU Equity Awards (in thousands)	Weighted Average Grant Date Fair Value
Unvested, beginning of the period	677	$34.57	269	$102.48
Granted (1)	636	$38.46	556	$21.20
Vested (2)	(205)	$39.23	(106)	$100.23
Forfeited	(73)	$36.83	—	$—
Unvested, end of the period	1,035	$35.88	719	$39.99

(1) Includes zero target performance-based RSU Equity Awards granted during both the three and six months ended June 30, 2021 and 25.8 thousand and 111.2 thousand during the three and six months ended June 30, 2020, respectively.

(2) The fair value of shares vested was $7.4 million and $0.6 million during the three months ended June 30, 2021 and 2020, respectively, and $ 7.8 million and $1.3 million for the six months ended June 30, 2021 and 2020, respectively.

Grant activity for the six months ended June 30,2021 and 2020 primarily consisted of RSU Equity Awards granted to executives and employees as part of the annual grant of long-term equity incentive awards.

No performance-based RSU Equity Awards were granted during the six months ended June 30,2021. For the performance-based RSU Equity Awards granted in the first half of 2020, the number of outstanding performance-based RSU Equity Awards that can vest is based on a calculation that compares the Company's total shareholder return ("TSR") to the same calculated return of a group of peer companies selected by the Company and can range between 0% and 300% of the target units for the awards granted. These awards include an absolute TSR modifier, which was added as a second factor in the calculation, which could increase the number of awards that vest or reduce the number of awards that vest if the absolute TSR is less than 5% over the performance period.

The Company recognizes expense for performance-based RSU Equity Awards based on the fair value of the awards at the grant date. Awards with a performance-based provision do not allow for the reversal of previously recognized expense, even if the market metric is not achieved and no shares ultimately vest. The grant date fair value of performance-based RSU Equity Awards, calculated using a Monte Carlo simulation, was $0.5 million and $3.4 million for the three and six months ended June 30, 2020, respectively. The following table summarizes the assumptions used to calculate the grant date fair value of the performance-based RSU Equity Awards granted during the three and six months ended June 30, 2020:

Performance-based Awards	June 29, 2020	January 31, 2020
Expected term (in years)	2.5	2.9
Expected volatility	113.2 %	54.8 %
Risk-free interest rate	0.2 %	1.3 %
Dividend yield	— %	— %

As of June 30, 2021, unrecognized compensation costs related to unvested RSU Equity Awards were $29.5 million and will be recognized over a weighted average period of 2.3 years.

Cash-Settled RSU Awards

The table below summarizes the activity for restricted stock units that may be settled in cash ("Cash-Settled RSU Awards") for the three and six months ended June 30, 2021 and 2020:

	Three Months Ended June 30,			
	2021		2020	
	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant Date Fair Value	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant Date Fair Value
Unvested, beginning of the period	194	$47.15	171	$78.54
Granted [(1)]	3	$36.71	39	$20.33
Vested	—	$—	(1)	$166.60
Did not vest at end of performance period	—	$—	(1)	$166.60
Forfeited	(23)	$54.57	—	$—
Unvested, end of the period	174	$45.93	208	$67.20

	Six Months Ended June 30,			
	2021		2020	
	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant Date Fair Value	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant Date Fair Value
Unvested, beginning of the period	196	$47.56	86	$124.22
Granted [(1)]	3	$36.71	125	$29.76
Vested	(1)	$110.48	(2)	$126.51
Did not vest at end of performance period	(1)	$110.48	(1)	$166.60
Forfeited	(23)	$54.57	—	$—
Unvested, end of the period	174	$45.93	208	$67.20

(1) Includes 3.2 thousand and 12.7 thousand units for the three months ended June 30, 2021 and 2020, respectively, and 3.2 thousand and 13.7 thousand units for the six months ended June 30, 2021 and 2020, respectively, associated with deferrals of certain non-employee director compensation pursuant to the terms of the Amended and Restated Deferred Compensation Plan for Outside Directors.

No Cash-Settled RSU Awards were granted to employees during the six months ended June 30, 2021. Grant activity in the first quarter of 2020 primarily consisted of Cash-Settled RSU Awards to executives as part of the annual grant of long-term equity incentive awards. These awards cliff vest after an approximate three-year performance period.

The Company's outstanding Cash-Settled RSU Awards include the same performance-based vesting conditions as the performance-based RSU Equity Awards, which are described above. Additionally, the assumptions used to calculate the grant date fair value per Cash-Settled RSU Award granted during the six months ended June 30, 2020 are the same as the performance-based RSU Equity Awards presented above.

The following table summarizes the Company's liability for Cash-Settled RSU Awards and the classification in the consolidated balance sheets for the periods indicated:

	June 30, 2021	December 31, 2020
	(In thousands)	
Other current liabilities	$996	$182
Other long-term liabilities	7,789	1,336
Total Cash-Settled RSU Awards	$8,785	$1,518

As of June 30, 2021, unrecognized compensation costs related to unvested Cash-Settled RSU Awards were $5.9 million and will be recognized over a weighted average period of 1.5 years.

Cash-Settled SARs

As a result of the Carrizo Acquisition, cash-settled stock appreciation rights ("Cash SARs") previously granted by Carrizo that were outstanding at closing were canceled and converted into a Cash SAR covering shares of the Company's common stock, with the conversion calculated as prescribed in the agreement governing the Carrizo Acquisition. The liabilities for Cash SARs as of June 30, 2021 and December 31, 2020 were $10.2 million and $1.7 million, respectively, all of which were classified as "Other current liabilities" in the consolidated balance sheets in the respective periods. Changes in the fair value of the Cash SARs are included in "General and administrative" in the consolidated statements of operations.

Share-Based Compensation Expense (Benefit), Net

Share-based compensation expense associated with the RSU Equity Awards, Cash-Settled RSU Awards, Cash SARs, net of amounts capitalized, is included in "General and administrative" in the consolidated statements of operations. The following table presents share-based compensation expense (benefit), net for each respective period:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2021	2020	2021	2020
	(In thousands)			
RSU Equity Awards	$3,242	$3,212	$5,850	$7,160
Cash-Settled RSU Awards	3,007	596	7,449	(1,400)
Cash SARs	3,676	1,115	8,542	(3,641)
	9,925	4,923	21,841	2,119
Less: amounts capitalized to oil and gas properties	(4,646)	(2,162)	(8,954)	(2,330)
Total share-based compensation expense (benefit), net	$5,279	$2,761	$12,887	($211)

See "Note 10 - Share-Based Compensation" of the Notes to Consolidated Financial Statements in the 2020 Annual Report for details of the Company's equity-based incentive plans.

Note 11 - Stockholders' Equity

Increase in Authorized Common Shares

The Company filed an amendment to its certificate of incorporation, which became effective on May 14, 2021, to increase the number of authorized shares of common stock from 52,500,000 to 78,750,000, as approved by the Company's shareholders at the 2021 Annual Meeting of Shareholders on May 14, 2021.

Warrant Exercises

During the six months ended June 30, 2021, certain holders of the September 2020 Warrants and warrants issued in conjunction with the exchange of Senior Unsecured Notes on November 2, 2020 (the "November 2020 Warrants") provided notice and exercised all of their outstanding warrants. As a result of the exercises, the Company issued a total of 6.4 million shares of its common stock in exchange for8.4 million outstanding warrants determined on a net share settlement basis. See "Note 7 - Derivative Instruments and Hedging Activities" and "Note 8 - Fair Value Measurements" for additional details regarding the September 2020 Warrants. As of June 30, 2021, 0.6 million November 2020 Warrants remain outstanding.

Reverse Stock Split

On August 7, 2020, the Board of Directors effected a reverse stock split of the Company's outstanding shares of common stock at a ratio of 1-for-10 and reduced the total number of authorized shares of the Company's common stock from 525,000,000 to 52,500,000 shares pursuant to an amendment to the Company's Certificate of Incorporation, which was approved by the Company's shareholders at the Company's annual meeting of shareholders on June 8, 2020. The Company's common stock began trading on a split-adjusted basis on August 10, 2020 upon opening of the markets. All share and per share amounts, except par value per share, in the consolidated financial statements and notes thereto for periods prior to August 2020 were retroactively adjusted to give effect to this reverse stock split.

Note 12 - Accounts Receivable, Net

	June 30, 2021	December 31, 2020
	(In thousands)	
Oil and natural gas receivables	$148,663	$100,257
Joint interest receivables	12,869	11,530
Other receivables	41,585	24,191
Total	203,117	135,978
Allowance for credit losses	(2,871)	(2,869)
Total accounts receivable, net	$200,246	$133,109

Note 13 - Accounts Payable and Accrued Liabilities

	June 30, 2021	December 31, 2020
	(In thousands)	
Accounts payable	$92,549	$101,231
Revenues payable	224,812	162,762
Accrued capital expenditures	57,355	32,493
Accrued interest	44,718	45,033
Total accounts payable and accrued liabilities	$419,434	$341,519

Note 14 - Supplemental Cash Flow

	Six Months Ended June 30,	
	2021	2020
	(In thousands)	
Supplemental cash flow information:		
Interest paid, net of capitalized amounts	$44,734	$31,649
Income taxes paid	—	—
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$14,576	$26,110
Investing cash flows from operating leases	8,402	11,278
Non-cash investing and financing activities:		
Change in accrued capital expenditures	$47,247	($6,186)
Change in asset retirement costs	2,567	207
ROU assets obtained in exchange for lease liabilities:		
Operating leases	$9,710	$2,666

Note 15 - Subsequent Events

Senior Unsecured Notes

On June 21, 2021, the Company entered into a Purchase Agreement pursuant to which it agreed to issue and sell $650.0 million in aggregate principal amount of 8.00% senior unsecured notes due 2028 (the "8.00% Senior Notes") in a private placement, which closed on July 6, 2021 for proceeds of approximately $638.1 million, net of underwriting discounts and commissions and offering costs. The 8.00% Senior Notes mature on August 1, 2028 and interest is payable on the Notes semi-annually each February 1 and August 1, commencing on February 1, 2022.

At any time prior to August 1, 2024, the Company may, from time to time, redeem up to 35% of the aggregate principal amount of the 8.00% Senior Notes in an amount of cash not greater than the net cash proceeds from certain equity offerings at the redemption price of 108.00% of the principal amount, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption, if at least 65% of the aggregate principal amount of the 8.00% Senior Notes remains outstanding after such redemption and the redemption occurs within 180 days of the closing date of such equity offering. Prior to August 1, 2024, the Company may, at its option, on any one or more occasions, redeem all or a portion of the 8.00% Senior Notes at 100.00% of the principal amount plus an applicable make-whole premium and accrued and unpaid interest. On or after August 1, 2024, the Company may redeem all or a portion of the 8.00% Senior Notes at redemption prices decreasing annually from 104.00% to 100.00% of the principal amount redeemed plus accrued and unpaid interest. Upon the occurrence of certain kinds of change of control, each holder of the 8.00% Senior Notes may require the Company to repurchase all or a portion of the 8.00% Senior Notes for cash at a price equal to 101% of the aggregate principal amount of such Notes, plus accrued and unpaid interest.

Also on June 21, 2021, the Company delivered a redemption notice with respect to all $542.7 million of its outstanding 6.25% Senior Notes, which became redeemable on July 21, 2021. The Company used a portion of the net proceeds from the 8.00% Senior Notes to redeem all of its outstanding 6.25% Senior Notes and the remaining proceeds to partially repay amounts outstanding under its Credit Facility.

Primexx Acquisition

On August 3, 2021, the Company entered into purchase and sale agreements with Primexx Resource Development, LLC and BPP Acquisition, LLC (collectively, the "Primexx PSAs") to purchase, effective as of July 1, 2021, certain producing oil and gas properties and undeveloped acreage in the Delaware Basin for total consideration of $440.0 million in cash and 9.19 million shares of Company common stock, subject to customary purchase price adjustments, with closing expected to occur early in the fourth quarter of 2021, subject to completion of various customary conditions (the "Primexx Acquisition"). Upon signing the Primexx PSAs, the Company paid approximately $60.1 million as a deposit into third-party escrow accounts.

Second Lien Note Exchange

Also on August 3, 2021, the Company entered into an agreement with Chambers Investments, LLC, a private investment vehicle managed by Kimmeridge Energy, to exchange $197.0 million of its outstanding Second Lien Notes for a notional amount of approximately $223.1 million of Company common stock. The value of equity to be delivered is based on the construct of the optional redemption language in the indenture for the Second Lien Notes. The price of the Company common stock used to calculate the shares issued is based on the 10-day volume-weighted average price as of August 2, 2021. This exchange is contingent upon the closing of the Primexx Acquisition described above as well as a shareholder vote as required under New York Stock Exchange rules because Kimmeridge is a deemed related party due to its ownership of over 5% of the Company's common stock.

Special Note Regarding Forward Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-Q by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- our oil and natural gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future capital and operating costs;
- production decline rates from our wells being greater than expected;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to consummate and efficiently integrate recent acquisitions; and
- prospect development and property acquisitions.

We caution you that the forward-looking statements contained in this Form 10-Q are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These and other risks include, but are not limited to, the risks described in Part I, Item 1A of our 2020 Annual Report and in all quarterly reports on Form 10-Q filed subsequently thereto. These factors include:

- volatility of oil, natural gas and NGL prices or a prolonged period of low oil, natural gas or NGLs prices;
- general economic conditions including the availability of credit and access to existing lines of credit;
- changes in the supply of and demand for oil and natural gas, including as a result of the COVID-19 pandemic and various governmental actions taken to mitigate its impact or actions by, or disputes among, members of OPEC and other oil and natural gas producing countries, such as Russia, with respect to production levels or other matters related to the price of oil;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, waste and water disposal infrastructure, and personnel;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the potential impact of future drilling on production from existing wells;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- cyberattacks on the Company or on systems and infrastructure used by the oil and natural gas industry; and
- weather conditions.

Should one or more of these risks or uncertainties occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Additional risks or uncertainties that are not currently known to us, that we currently deem to be immaterial, or that could apply to any company could also materially adversely affect our business, financial condition, or future results. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

In addition, we caution that reserve engineering is a process of estimating oil and natural gas accumulated underground and cannot be measured exactly. Accuracy of reserve estimates depend on a number of factors including data available at the point in time, engineering interpretation of the data, and assumptions used by the reserve engineers as it relates to price and cost estimates and recoverability. New results of drilling, testing, and production history may result in revisions of previous estimates and, if significant, would impact future development plans. As such, reserve estimates may differ from actual results of oil and natural gas quantities ultimately recovered.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following management's discussion and analysis describes the principal factors affecting the Company's results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying unaudited consolidated financial statements and our 2020 Annual Report on Form 10-K, which include additional information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results. Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this Quarterly Report on Form 10-Q.

We are an independent oil and natural gas company with roots that go back over 70 years to our establishment in 1950. We are focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. Our activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas, as well as the Eagle Ford in South Texas.

Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals in the Permian, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales, and the Eagle Ford. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and through acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps.

Recent Developments and Overview

Senior Unsecured Notes

On June 21, 2021, we entered into a Purchase Agreement pursuant to which we agreed to issue and sell $650.0 million in aggregate principal amount of 8.00% Senior Notes in a private placement, which closed on July 6, 2021 for proceeds of approximately $638.1 million, net of underwriting discounts and commissions and offering costs. Also on June 21, 2021, we delivered a redemption notice with respect to all $542.7 million of our outstanding 6.25% Senior Notes, which became redeemable on July 21, 2021. We used a portion of the net proceeds from the 8.00% Senior Notes to redeem all of our outstanding 6.25% Senior Notes and the remaining proceeds to partially repay amounts outstanding under our Credit Facility. See "Note 15 - Subsequent Events" for further discussion.

Primexx Acquisition and Second Lien Note Exchange

On August 3, 2021, we entered into the Primexx PSAs to purchase, effective as of July 1, 2021, certain producing oil and gas properties and undeveloped acreage in the Delaware Basin for total consideration of $440.0 million in cash and 9.19 million shares of our common stock, subject to customary purchase price adjustments. Also on August 3, 2021, we entered into an agreement with Chambers Investments, LLC, a private investment vehicle managed by Kimmeridge Energy, to exchange $197.0 million of our outstanding Second Lien Notes for a notional amount of approximately $223.1 million of our common stock, contingent upon the closing of the Primexx Acquisition described above as well as a required shareholder vote. See "Note 15 - Subsequent Events" for further discussion.

Second Quarter 2021 Highlights

- Total production for the three months ended June 30, 2021 was 89.0 MBoe/d, an increase of10% from the three months ended March 31, 2021, primarily due to new wells placed on production during the second quarter of 2021 as well as lower production in the first quarter of 2021 as a result of the shut-in of our operated production during the severe winter storms in February 2021. Total production for the six months ended June 30, 2021 was 85.0 MBoe/d, a decrease of 19% from the six months ended June 30, 2020, primarily due to normal production decline partially offset by new wells placed on production during 2021.
- Operated drilling and completion activity for the three months ended June 30, 2021 along with our drilled but uncompleted and producing wells as of June 30, 2021 are summarized in the table below.

	Three Months Ended June 30, 2021				As of June 30, 2021			
	Drilled		Completed		Drilled But Uncompleted		Producing	
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian	8	6.5	22	20.2	15	11.9	847	738.1
Eagle Ford	—	—	29	29.0	6	6.0	689	621.1
Total	8	6.5	51	49.2	21	17.9	1,536	1,359.2

- Operational capital expenditures, exclusive of leasehold and seismic, for the second quarter of 2021 were$138.3 million, of which approximately 63% were in the Permian with the remaining balance in the Eagle Ford. See "—Liquidity and Capital Resources—2021 Capital Budget and Funding Strategy" for additional details.
- Completed divestitures of certain non-core assets in the Delaware Basin for aggregate net cash proceeds of$30.7 million, subject to post-closing adjustments. See "Note 3 - Acquisitions and Divestitures" for further discussion.
- Entered into the fourth amendment to our credit agreement governing the Credit Facility which, among other things reaffirmed the borrowing base and the elected commitment amount of $1.6 billion as a result of the spring 2021 scheduled redetermination. See "Note 6 - Borrowings" for further discussion.
- Reduced borrowings outstanding under our Credit Facility by $75.0 million compared to the first quarter of 2021, reflecting our continued emphasis on deleveraging our balance sheet.
- We recorded net loss for the three months ended June 30, 2021 and 2020 of$11.7 million, or $0.25 per diluted share, and $1.6 billion, or $39.41 per diluted share, respectively. The variance between the respective periods was driven primarily by the impairment of evaluated properties of $1.3 billion during the second quarter of 2020 as well as an increase in operating revenues in the second quarter of 2021 driven by an approximate 206% increase in the total average realized sales price compared to the second quarter of 2020 as well as a decrease in depreciation, depletion and amortization primarily driven by the recording of impairments of evaluated oil and gas properties during 2020, partially offset by an increase in the loss on derivative contracts to approximately $190.5 million during the second quarter of 2021 compared to approximately $127.0 million during the second quarter of 2020. See "—Results of Operations" below for further details.

Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	Three Months Ended				Six Months Ended June 30,			
	June 30, 2021	March 31, 2021	$ Change	% Change	2021	2020	$ Change	% Change
Total production								
Oil (MBbls)								
Permian	3,232	3,088	144	5 %	6,320	7,227	(907)	(13 %)
Eagle Ford	1,870	1,593	277	17 %	3,463	5,016	(1,553)	(31 %)
Total oil (MBbls)	5,102	4,681	421	9 %	9,783	12,243	(2,460)	(20 %)
Natural gas (MMcf)								
Permian	7,138	6,208	930	15 %	13,346	16,745	(3,399)	(20 %)
Eagle Ford	1,745	1,627	118	7 %	3,372	4,057	(685)	(17 %)
Total natural gas (MMcf)	8,883	7,835	1,048	13 %	16,718	20,802	(4,084)	(20 %)
NGLs (MBbls)								
Permian	1,216	1,075	141	13 %	2,291	2,636	(345)	(13 %)
Eagle Ford	299	224	75	33 %	523	728	(205)	(28 %)
Total NGLs (MBbls)	1,515	1,299	216	17 %	2,814	3,364	(550)	(16 %)
Total Production (MBoe)								
Permian	5,637	5,198	439	8 %	10,835	12,654	(1,819)	(14 %)
Eagle Ford	2,460	2,088	372	18 %	4,548	6,420	(1,872)	(29 %)
Total barrels of oil equivalent (MBoe)	8,097	7,286	811	11 %	15,383	19,074	(3,691)	(19 %)
Total daily production (Boe/d)	88,981	80,957	8,024	10 %	84,991	104,802	(19,811)	(19 %)
Oil as % of total daily production	63 %	64 %			64 %	64 %		
Benchmark prices (1)								
WTI (per Bbl)	$66.06	$57.80	$8.26	14 %	$61.95	$36.97	$24.98	68 %
Henry Hub (per Mcf)	2.97	2.72	0.25	9 %	2.85	1.81	1.04	57 %
Average realized sales price (excluding impact of settled derivatives)								
Oil (per Bbl)								
Permian	$65.08	$56.66	$8.42	15 %	$60.97	$34.38	$26.59	77 %
Eagle Ford	65.83	57.80	8.03	14 %	62.14	29.47	32.67	111 %
Total oil (per Bbl)	65.36	57.05	8.31	15 %	61.38	32.37	29.01	90 %
Natural gas (per Mcf)								
Permian	2.68	3.11	(0.43)	(14 %)	2.88	0.66	2.22	336 %
Eagle Ford	2.82	3.03	(0.21)	(7 %)	2.92	1.80	1.12	62 %
Total natural gas (per Mcf)	2.71	3.09	(0.38)	(12 %)	2.89	0.88	2.01	228 %
NGL (per Bbl)								
Permian	24.71	22.68	2.03	9 %	23.76	9.93	13.83	139 %
Eagle Ford	22.00	22.24	(0.24)	(1 %)	22.10	8.81	13.29	151 %
Total NGLs (per Bbl)	24.17	22.60	1.57	7 %	23.45	9.69	13.76	142 %

	Three Months Ended				Six Months Ended June 30,			
	June 30, 2021	March 31, 2021	$ Change	% Change	2021	2020	$ Change	% Change
Total average realized sales price (per Boe)								
Permian	46.04	42.06	3.98	9 %	44.13	22.57	21.56	96 %
Eagle Ford	54.72	48.85	5.87	12 %	52.02	25.16	26.86	107 %
Total (per Boe)	$48.68	$44.01	$4.67	11 %	$46.46	$23.44	$23.02	98 %
Average realized sales price (including impact of settled derivatives)								
Oil (per Bbl)	$46.82	$44.33	$2.49	6 %	$45.63	$41.02	$4.61	11 %
Natural gas (per Mcf)	2.25	2.88	(0.63)	(22 %)	2.54	1.04	1.50	144 %
NGLs (per Bbl)	23.21	21.77	1.44	7 %	22.54	9.69	12.85	133 %
Total (per Boe)	$36.31	$35.46	$0.85	2 %	$35.91	$29.18	$6.73	23 %
Revenues (in thousands)								
Oil								
Permian	$210,340	$174,967	$35,373	20 %	$385,307	$248,444	$136,863	55 %
Eagle Ford	123,102	92,078	31,024	34 %	215,180	147,836	67,344	46 %
Total oil	333,442	267,045	66,397	25 %	600,487	396,280	204,207	52 %
Natural gas								
Permian	19,152	19,290	(138)	(1 %)	38,442	10,984	27,458	250 %
Eagle Ford	4,928	4,930	(2)	— %	9,858	7,287	2,571	35 %
Total natural gas	24,080	24,220	(140)	(1 %)	48,300	18,271	30,029	164 %
NGLs								
Permian	30,047	24,376	5,671	23 %	54,423	26,188	28,235	108 %
Eagle Ford	6,578	4,981	1,597	32 %	11,559	6,414	5,145	80 %
Total NGLs	36,625	29,357	7,268	25 %	65,982	32,602	33,380	102 %
Total Revenues								
Permian	259,539	218,633	40,906	19 %	478,172	285,616	192,556	67 %
Eagle Ford	134,608	101,989	32,619	32 %	236,597	161,537	75,060	46 %
Total revenues	$394,147	$320,622	$73,525	23 %	$714,769	$447,153	$267,616	60 %
Additional per Boe data								
Lease operating								
Permian	$4.60	$4.31	$0.29	7 %	$4.46	$5.00	($0.54)	(11 %)
Eagle Ford	8.34	8.65	(0.31)	(4 %)	8.49	6.22	2.27	36 %
Total lease operating	$5.74	$5.55	$0.19	3 %	$5.65	$5.41	$0.24	4 %
Production and ad valorem taxes								
Permian	$2.53	$2.32	$0.21	9 %	$2.43	$1.55	$0.88	57 %
Eagle Ford	3.12	3.07	0.05	2 %	3.10	1.62	1.48	91 %
Total production and ad valorem taxes	$2.71	$2.53	$0.18	7 %	$2.63	$1.57	$1.06	68 %
Gathering, transportation and processing								
Permian	$2.75	$2.54	$0.21	8 %	$2.65	$2.09	$0.56	27 %
Eagle Ford	1.84	2.29	(0.45)	(20 %)	2.05	1.23	0.82	67 %
Total gathering, transportation and processing	$2.47	$2.47	$—	— %	$2.47	$1.80	$0.67	37 %

(1) Reflects calendar average daily spot market prices.

Revenues

The following table is intended to reconcile the change in oil, natural gas, NGLs, and total revenue for the respective period presented by reflecting the effect of changes in volume and in the underlying commodity prices:

	Three Months Ended			
	Oil	Natural Gas	NGLs	Total
	(In thousands)			
Revenues for the period ended in March 31, 2021 (1)	$267,045	$24,220	$29,357	$320,622
Volume increase (decrease)	24,018	3,240	4,881	32,139
Price increase (decrease)	42,379	(3,380)	2,387	41,386
Net increase (decrease)	66,397	(140)	7,268	73,525
Revenues for the period ended in June 30, 2021 (1)	$333,442	$24,080	$36,625	$394,147
Percent of total revenues	85 %	6 %	9 %	

(1) Excludes sales of oil and gas purchased from third parties.

	Six Months Ended June 30,			
	Oil	Natural Gas	NGLs	Total
	(In thousands)			
Revenues for the period ended in 2020	$396,280	$18,271	$32,602	$447,153
Volume increase (decrease)	(79,625)	(3,587)	(5,330)	(88,542)
Price increase (decrease)	283,832	33,616	38,710	356,158
Net increase (decrease)	204,207	30,029	33,380	267,616
Revenues for the period ended in 2021 (1)	$600,487	$48,300	$65,982	$714,769
Percent of total revenues	84 %	7 %	9 %	

(1) Excludes sales of oil and gas purchased from third parties.

Revenues for the three months ended June 30, 2021 of $394.1 million increased $73.5 million, or 23%, compared to revenues of $320.6 million for the three months ended March 31, 2021. The increase was primarily attributable to an 11% increase in the average realized sales price which rose to $48.68 per Bbl from $44.01 per Bbl as well as a 10% increase in production as discussed above.

Revenues for the six months ended June 30, 2021 of $714.8 million increased $267.6 million, or 60%, compared to revenues of $447.2 million for the same period of 2020. The increase was primarily attributable to a 98% increase in the average realized sales price which rose to $46.46 per Bbl from $23.44 per Bbl. The increase in the average realized sales price was partially offset by a 19% decrease in production as discussed above.

Operating Expenses

	Three Months Ended							
		Per		Per	Total Change		Boe Change	
	June 30, 2021	Boe	March 31, 2021	Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Lease operating	$46,460	$5.74	$40,453	$5.55	$6,007	15 %	$0.19	3 %
Production and ad valorem taxes	21,958	2.71	18,439	2.53	3,519	19 %	0.18	7 %
Gathering, transportation and processing	20,031	2.47	17,981	2.47	2,050	11 %	—	— %
Depreciation, depletion and amortization	83,128	10.27	70,987	9.74	12,141	17 %	0.53	5 %
General and administrative	11,065	1.37	16,799	2.31	(5,734)	(34 %)	(0.94)	(41 %)
Impairment of evaluated oil and gas properties	—	—	—	—	—	— %	—	— %
Merger and integration	—	—	—	—	—	— %	—	— %

	Six Months Ended June 30,							
		Per		Per	Total Change		Boe Change	
	2021	Boe	2020	Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Lease operating	$86,913	$5.65	$103,221	$5.41	($16,308)	(16 %)	$0.24	4 %
Production and ad valorem taxes	40,397	2.63	30,041	1.57	10,356	34 %	1.06	68 %
Gathering, transportation and processing	38,012	2.47	34,415	1.80	3,597	10 %	0.67	37 %
Depreciation, depletion and amortization	154,115	10.02	270,393	14.18	(116,278)	(43 %)	(4.16)	(29 %)
General and administrative	27,864	1.81	18,349	0.96	9,515	52 %	0.85	89 %
Impairment of evaluated oil and gas properties	—	—	1,276,518	66.92	(1,276,518)	(100 %)	(66.92)	(100 %)
Merger and integration	—	—	23,897	1.25	(23,897)	(100 %)	(1.25)	(100 %)

Lease operating expenses. These are daily costs incurred to extract oil, natural gas and NGLs and maintain our producing properties. Such costs also include maintenance, repairs, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

Lease operating expenses for the three months ended June 30, 2021 increased to $46.5 million compared to $40.5 million for the three months ended March 31, 2021, primarily due to production volumes increasing 11%. Lease operating expense per Boe for the three months ended June 30, 2021 increased to $5.74 compared to $5.55 for the three months ended March 31, 2021, primarily due to increased electrical costs.

Lease operating expenses for the six months ended June 30, 2021 decreased to $86.9 million compared to $103.2 million for the same period of 2020, primarily due to production volumes decreasing 19%. Lease operating expense per Boe for the six months ended June 30, 2021 increased to $5.65 compared to $5.41 for the same period of 2020, primarily due to the distribution of fixed costs spread over lower production volumes, partially offset by a reduction in certain operating expenses including repairs and maintenance and production chemicals.

Production and ad valorem taxes. In general, severance taxes are based upon current year commodity prices whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. We benefit from tax credits and exemptions in our various taxing jurisdictions where available and applicable. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties.

For the three months ended June 30, 2021, production and ad valorem taxes increased 19% to $22.0 million compared to $18.4 million for the three months ended March 31, 2021, which is primarily related to a 23% increase in total revenues which increased production taxes. Production and ad valorem taxes as a percentage of total revenues decreased to 5.6% for the second quarter of 2021 as compared to 5.8% of total revenues for the three months ended March 31, 2021, primarily due to total revenues increasing at a higher rate than the increase in ad valorem taxes.

For the six months ended June 30, 2021, production and ad valorem taxes increased 34% to $40.4 million compared to $30.0 million for the same period of 2020, which is primarily related to a 60% increase in total revenues which increased production taxes. The impact of the increase in production taxes was partially offset by a decrease in ad valorem taxes due to lower expected property tax valuations for 2021 as a result of lower commodity prices during 2020 compared to higher property tax valuations for 2020 as a result of higher commodity prices during 2019. Production and ad valorem taxes as a percentage of total revenues decreased to 5.7% for the six months ended June 30, 2021, as compared to 6.7% of total revenues for the same period of 2020, primarily due to lower expected property tax valuations for 2021 as a result of lower commodity prices during 2020.

Gathering, transportation and processing expenses. For the three months ended June 30, 2021, gathering, transportation and processing expenses increased 11% to $20.0 million compared to $18.0 million for the three months ended March 31, 2021, which is primarily related to the 11% increase in production volumes between the two periods.

For the six months ended June 30, 2021, gathering, transportation and processing expenses increased 10% to $38.0 million compared to $34.4 million for the same period of 2020, which was primarily related to new oil transportation agreements which were executed subsequent to the three months ended March 31, 2020, partially offset by a 19% decrease in production volumes between the two periods.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically amortize those costs on an equivalent unit-of-production method based on production and estimated proved oil and gas reserve quantities. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to twenty years. The following table sets forth the components of our depreciation, depletion and amortization for the periods indicated:

	Three Months Ended				Six Months Ended June 30,			
	June 30, 2021		March 31, 2021		2021		2020	
	Amount	Per Boe	Amount	Per Boe	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per Boe)							
DD&A of evaluated oil and gas properties	$80,833	$9.98	$68,705	$9.43	$149,538	$9.72	$265,654	$13.93
Depreciation of other property and equipment	489	0.06	516	0.07	1,005	0.07	2,072	0.11
Amortization of other assets	883	0.11	839	0.11	1,722	0.11	995	0.05
Accretion of asset retirement obligations	923	0.12	927	0.13	1,850	0.12	1,672	0.09
DD&A	$83,128	$10.27	$70,987	$9.74	$154,115	$10.02	$270,393	$14.18

For the three months ended June 30, 2021, DD&A increased to $83.1 million from $71.0 million for the three months ended March 31, 2021. The increase in DD&A was primarily attributable to a production increase of 11%, higher capital expenditures during the second quarter of 2021 as compared to the first quarter of 2021 and increases in future development cost assumptions.

For the six months ended June 30, 2021, DD&A decreased to $154.1 million from $270.4 million for the same period in 2020. The decrease in DD&A was primarily attributable to a production decrease of 19% and as a result of the impairments of evaluated oil and gas properties that were recognized during 2020.

General and administrative, net of amounts capitalized ("G&A"). G&A for the three months ended June 30, 2021 decreased to $11.1 million compared to $16.8 million for the three months ended March 31, 2021, primarily due to lower compensation costs and a decrease in share-based compensation expense, net as the fair value of Cash-Settled RSU Awards and Cash SARs did not increase in the second quarter of 2021 at the same rate as in the first quarter of 2021.

G&A for the six months ended June 30, 2021 increased to $27.9 million compared to $18.3 million for the same period in 2020 primarily due to an increase in the fair value of Cash-Settled RSU Awards and Cash SARs, partially offset by lower compensation costs.

Impairment of evaluated oil and gas properties. We did not recognize an impairment of evaluated oil and gas properties for the three or six months ended June 30, 2021 or three months ended March 31, 2021. An impairment of evaluated oil and gas properties of $1.3 billion was recognized for six months ended June 30, 2020, which was due primarily to declines in the 12-Month Average Realized Price of crude oil. See "Note 4 - Property and Equipment, Net" for further discussion.

Merger and integration expense. For the three and six months ended June 30, 2021 as well as the three months ended March 31, 2021, we incurred no merger and integration expenses compared to $23.9 million for the six months ended June 30, 2020, which were related to the Carrizo Acquisition.

Other Income and Expenses

Interest expense, net of capitalized amounts. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees, and interest from our financing leases in interest expense. The following table sets forth the components of our interest expense, net of capitalized amounts for the periods indicated:

	Three Months Ended			Six Months Ended June 30,		
	June 30, 2021	March 31, 2021	$ Change	2021	2020	$ Change
			(In thousands)			
Interest expense on Credit Facility	$7,970	$7,817	$153	$15,787	$24,320	($8,533)
Interest expense on Second Lien Notes	11,625	11,625	—	23,250	—	23,250
Interest expense on Senior Unsecured Notes	24,502	24,502	—	49,004	61,750	(12,746)
Amortization of debt issuance costs, premiums and discounts	4,438	4,478	(40)	8,916	1,892	7,024
Other interest expense	26	32	(6)	58	107	(49)
Capitalized interest	(23,927)	(24,038)	111	(47,965)	(44,909)	(3,056)
Interest expense, net of capitalized amounts	$24,634	$24,416	$218	$49,050	$43,160	$5,890

Interest expense, net of capitalized amounts, incurred during the three months ended June 30, 2021 remained consistent at $24.6 million compared to $24.4 million for the three months ended March 31, 2021.

Interest expense, net of capitalized amounts, incurred during the six months ended June 30, 2021 increased $5.9 million to $49.1 million compared to $43.2 million for the same period of 2020. The increase is primarily due to the issuance of the Second Lien Notes in the third quarter of 2020 as well as amortization of the discount associated with those Second Lien Notes, offset by the reduction in Senior Unsecured Notes outstanding as a result of the exchange which occurred during the fourth quarter of 2020 and lower borrowings on the Credit Facility during the same period of 2020.

(Gain) loss on derivative contracts. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. (Gain) loss on derivative contracts represents the (i) (gain) loss related to fair value adjustments on our open derivative contracts and (ii) (gains) losses on settlements of derivative contracts for positions that have settled within the period. The net (gain) loss on derivative instruments for the periods indicated includes the following:

	Three Months Ended		Six Months Ended June 30,	
	June 30, 2021	March 31, 2021	2021	2020
		(In thousands)		
(Gain) loss on oil derivatives	$177,033	$149,561	$326,594	($134,954)
(Gain) loss on natural gas derivatives	12,816	2,697	15,513	11,524
(Gain) loss on NGL derivatives	3,734	1,138	4,872	(4)
(Gain) loss on contingent consideration arrangements	(3,120)	5,737	2,617	(1,570)
(Gain) loss on September 2020 Warrants liability	—	55,390	55,390	—
(Gain) loss on derivative contracts	$190,463	$214,523	$404,986	($125,004)

See “Note 7 - Derivative Instruments and Hedging Activities” and “Note 8 - Fair Value Measurements” for additional information.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate, based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

We recorded income tax benefit of $0.5 million and $0.9 million for the three months ended June 30, 2021 and March 31, 2021, respectively. Since the second quarter of 2020, we have concluded that it is more likely than not that the net deferred tax assets will not be realized and have recorded a full valuation allowance against our deferred tax assets. As long as we continue to conclude that the valuation allowance is necessary, we will not have significant deferred tax expense or benefit.

We recorded income tax benefit of $1.4 million for the six months ended June 30, 2021 compared to income tax expense of $115.3 million for the same period of 2020. The income tax expense for the six month period in 2020 is due to the recording of the valuation allowance during the three months ended June 30, 2020, which still remained as of June 30, 2021. See “Note 9 - Income Taxes” for further discussion.

Liquidity and Capital Resources

2021 Capital Budget and Funding Strategy. Our primary uses of capital are for the exploration and development of our oil and natural gas properties. Our 2021 capital budget has been established at up to $430.0 million, with approximately 80% directed towards drilling, completion, and equipment expenditures. Approximately 70% of our 2021 capital budget is allocated towards development in the Permian with the remaining 30% towards development in the Eagle Ford. As part of our 2021 operated horizontal drilling program, we expect to drill approximately 55 to 65 gross operated wells and complete approximately 90 to 100 gross operated wells. Our 2021 capital budget and the number of wells we expect to drill and complete discussed above does not contemplate incremental activity that may occur subsequent to the planned closing of the Primexx Acquisition.

During the three months ended June 30, 2021, we drilled 8 gross (6.5 net) wells, all in the Permian, and completed 51 gross (49.2 net) wells, with 29.0 net wells completed in Eagle Ford and 20.2 net wells completed in the Permian. We expect to operate an average of three to four drilling rigs and approximately one completion crew during the second half of 2021.

The following table is a summary of our capital expenditures[(1)] for the three and six months ended June 30, 2021:

	Three Months Ended		Six Months Ended
	March 31, 2021	**June 30, 2021**	**June 30, 2021**
		(In millions)	
Operational capital	$95.6	$138.3	$233.9
Capitalized interest	24.0	23.9	47.9
Capitalized G&A	11.2	12.1	23.3
Total	$130.8	$174.3	$305.1

(1) Capital expenditures, presented on an accrual basis, includes drilling, completions, facilities, and equipment, but excludes land, seismic, and asset retirement costs.

We continually evaluate our capital expenditure needs and compare them to our capital resources. Because we are the operator of a high percentage of our properties, we can control the amount and timing of our capital expenditures. We can choose to defer or accelerate a portion of our planned capital expenditures depending on various factors, including, but not limited to, depressed commodity prices, market conditions, our available liquidity and financing, acquisitions and divestitures of oil and gas properties, the availability of drilling rigs and completion crews, the cost of completion services, success of drilling programs, land and industry partner issues, weather delays, the acquisition of leases with drilling commitments, and other factors. We plan to execute a more moderated capital expenditure program through reduced reinvestment rates and balanced capital deployment for a more consistent cash flow generation and will be focused to further enhance our multi-zone, scale development program while leveraging our drilled, but uncompleted backlog to drive capital efficiency.

Historically, our primary sources of capital have been cash flows from operations, borrowings under our Credit Facility, proceeds from the issuance of debt securities and public equity offerings, and non-core asset dispositions. We regularly consider which resources, including debt and equity financings, are available to meet our future financial obligations, planned capital expenditures and liquidity requirements. In addition, depending upon our actual and anticipated sources and uses of liquidity, prevailing market conditions and other factors, we may, from time to time, seek to retire or repurchase our outstanding debt or equity securities through cash purchases in the open market or through privately negotiated transactions or otherwise. The amounts involved in any such transactions, individually or in aggregate, may be material.

We may continue to consider divesting certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth or enter into joint venture agreements, provided we are able to divest such assets or enter into joint venture agreements on terms that are acceptable to us.

Overview of Cash Flow Activities. For the six months ended June 30, 2021, cash and cash equivalents decreased $16.4 million to $3.8 million compared to $20.2 million at December 31, 2020.

	Six Months Ended June 30,	
	2021	**2020**
	(In thousands)	
Net cash provided by operating activities	$313,268	$289,496
Net cash used in investing activities	(217,387)	(453,656)
Net cash provided by (used in) financing activities	(112,317)	158,319
Net change in cash and cash equivalents	($16,436)	($5,841)

Operating activities. For the six months ended June 30, 2021, net cash provided by operating activities was $313.3 million compared to $289.5 million for the same period in 2020. The change in net cash provided by operating activities was predominantly attributable to the following:

- An increase in revenue primarily driven by a 90% increase in realized oil price, partially offset by a 19% decrease in production volumes,
- Changes in working capital as accounts receivable has increased from December 31, 2020 as a result of the increase in the price of oil,
- An offsetting decrease in the cash received from commodity derivative settlements, and
- An offsetting decrease in operating expenses as a result of lower production volumes as well as our continued improvement of managing our field operating costs.

Production, realized prices, and operating expenses are discussed in Results of Operations. See “Note 7 - Derivative Instruments and Hedging Activities” and “Note 8 - Fair Value Measurements” for a reconciliation of the components of our derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. For the six months ended June 30, 2021, net cash used in investing activities was $217.4 million compared to $453.7 million for the same period in 2020. The decrease in net cash used in investing activities was primarily attributed to the following:

- A decrease in operational capex during the six months ended June 30, 2021 compared to the same period in 2020,
- A decrease in cash paid for the settlement of contingent consideration agreements as net cash payments of $40.0 million were paid in January 2020 related to contingent considerations acquired in the Carrizo Acquisition, and
- An offsetting increase in cash received from the sale of assets due to the divestitures of certain non-core assets in the Delaware Basin.

Financing activities. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under the Credit Facility, term debt and equity offerings. For the six months ended June 30, 2021, net cash used in financing activities was $112.3 million compared to net cash provided by financing activities of $158.3 million for the same period of 2020. This change was primarily attributable to repayment of approximately $110.0 million on the Credit Facility during the six months ended June 30, 2021, which reflects our continued commitment and focus on deleveraging.

See “Note 6 - Borrowings” for additional information on our debt transactions.

Contractual Obligations. Our contractual obligations primarily consist of long-term debt, operating leases, asset retirement obligations, produced water disposal commitments, and gathering, processing and transportation service commitments. Since December 31, 2020, there have been no material changes to our contractual obligations other than the changes to the borrowings under our Credit Facility as discussed further in “Note 6 - Borrowings”. Also, see “Note 15 - Subsequent Events” for a discussion of the issuance of our 8.00% Senior Notes and the redemption of all of our 6.25% Senior Notes, which occurred subsequent toJune 30, 2021.

Credit Facility. As of June 30, 2021, our Credit Facility had a borrowing base of $1.6 billion, with an elected commitment amount of $1.6 billion, borrowings outstanding of $875.0 million at a weighted average interest rate of 2.61%, and $24.0 million in letters of credit outstanding. The borrowing base under the credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering our major producing properties. Upon a redetermination, if any borrowings in excess of the revised borrowing base were outstanding, we could be forced to immediately repay a portion of the borrowings outstanding under the credit agreement.

Our Credit Facility contains certain covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. Under the Credit Facility, we must maintain the following financial covenants determined as of the last day of the quarter, each as described above: (1) a Secured Leverage Ratio of no more than 3.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. We were in compliance with these covenants at June 30, 2021. If we are unable to remain in compliance with our restrictive financial covenants, we could be subject to lender elections for default resolution. However, we expect to have sufficient liquidity to pay interest on our Credit Facility (as well as on the Second Lien Notes and our Senior Unsecured Notes and to fund our development program).

The Credit Facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

See “Note 6 – Borrowings” for additional information related to the Credit Facility.

Hedging. As of August 2, 2021, the Company had the following outstanding oil, natural gas and NGL derivative contracts:

Oil contracts (WTI)	For the Remainder of 2021 [(1)]	For the Full Year of 2022 [(1)]	For the Full Year of 2023
Swap contracts			
Total volume (Bbls)	1,104,000	3,015,000	—
Weighted average price per Bbl	$42.10	$63.55	$—
Collar contracts			
Total volume (Bbls)	5,522,775	7,097,500	—
Weighted average price per Bbl			
Ceiling (short call)	$49.16	$67.70	$—
Floor (long put)	$40.71	$56.15	$—
Long put contracts			
Total volume (Bbls)	414,000	—	—
Weighted average price per Bbl	$62.50	$—	$—
Short call contracts			
Total volume (Bbls)	2,432,480 (2)	—	—
Weighted average price per Bbl	$63.62	$—	$—
Short call swaption contracts			
Total volume (Bbls)	—	1,825,000 (3)	1,825,000 (3)
Weighted average price per Bbl	$—	$52.18	$72.00
Oil contracts (Brent ICE)			
Swap contracts			
Total volume (Bbls)	— (4)	—	—
Weighted average price per Bbl	$—	$—	$—
Collar contracts			
Total volume (Bbls)	368,000	—	—
Weighted average price per Bbl			
Ceiling (short call)	$50.00	$—	$—
Floor (long put)	$45.00	$—	$—
Oil contracts (Midland basis differential)			
Swap contracts			
Total volume (Bbls)	1,504,400	—	—
Weighted average price per Bbl	$0.25	$—	$—
Oil contracts (Argus Houston MEH)			
Collar contracts			
Total volume (Bbls)	—	452,500	—
Weighted average price per Bbl			
Ceiling (short call)	$—	$63.15	$—
Floor (long put)	$—	$51.25	$—

(1) We have approximately $9.4 million of deferred premiums, of which $6.5 million are associated with contracts that will settle in 2021 and $2.9 million for contracts that will settle in 2022.
(2) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.
(3) The 2022 and 2023 short call swaption contracts have exercise expiration dates of December 31, 2021 and December 30, 2022, respectively.
(4) In February 2021, we entered into certain offsetting ICE Brent swaps to reduce our exposure to rising oil prices. Those offsetting swaps resulted in a locked-in loss of approximately $2.9 million, of which $1.6 million will be settled in the third quarter of 2021 with the remaining $1.3 million to be settled in the fourth quarter of 2021.

tural gas contracts (Henry Hub)	For the Remainder of 2021		For the Full Year of 2022
wap contracts			
Total volume (MMBtu)	7,301,000		7,320,000
Weighted average price per MMBtu	$2.61		$3.08
'ollar contracts			
Total volume (MMBtu)	3,680,000		5,740,000
Weighted average price per MMBtu			
Ceiling (short call)	$2.80		$3.64
Floor (long put)	$2.50		$2.83
hort call contracts			
Total volume (MMBtu)	3,680,000	(1)	—
Weighted average price per MMBtu	$3.09		$—
tural gas contracts (Waha basis differential)			
wap contracts			
Total volume (MMBtu)	8,280,000		5,475,000
Weighted average price per MMBtu	($0.42)		($0.21)

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

NGL contracts (OPIS Mont Belvieu Purity Ethane)	For the Remainder of 2021	For the Full Year of 2022
Swap contracts		
Total volume (Bbls)	920,000	—
Weighted average price per Bbl	$7.62	$—

Critical Accounting Policies

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. We have identified the following critical accounting policies and estimates used in the preparation of our financial statements: use of estimates, oil and gas properties, oil and gas reserve estimates, derivative instruments, contingent consideration arrangements, income taxes, and commitments and contingencies. These policies and estimates are described in "Note 2 - Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in our 2020 Annual Report. See "Note 7 - Derivative Instruments and Hedging Activities" and "Note 8 - Fair Value Measurements" for details of the contingent consideration arrangements. We evaluate subsequent events through the date the financial statements are issued.

The table below presents various pricing scenarios to demonstrate the sensitivity of our June 30, 2021 cost center ceiling to changes in 12-month average benchmark crude oil and natural gas prices underlying the 12-month average realized prices. The sensitivity analysis is as of June 30, 2021 and, accordingly, does not consider drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, changes in crude oil and natural gas prices, and changes in development and operating costs occurring subsequent to June 30, 2021 that may require revisions to estimates of proved reserves. See also "Part I, Item 1A. Risk Factors—If oil and natural gas prices remain depressed for extended periods of time, we may be required to make significant downward adjustments to the carrying value of our oil and natural gas properties" in our 2020 Annual Report.

Full Cost Pool Scenarios	12-Month Average Realized Prices Crude Oil ($/Bbl)	Natural Gas ($/Mcf)	Excess (deficit) of cost center ceiling over net book value, less related deferred income taxes (In millions)	Increase (decrease) of cost center ceiling over net book value, less related deferred income taxes (In millions)
June 30, 2021 Actual	$48.06	$1.55	$1,044	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$53.04	$1.79	$1,684	$640
Crude Oil and Natural Gas -10%	$43.08	$1.31	$406	($638)
Crude Oil Price Sensitivity				
Crude Oil +10%	$53.04	$1.55	$1,637	$593
Crude Oil -10%	$43.08	$1.55	$453	($591)
Natural Gas Price Sensitivity				
Natural Gas +10%	$48.06	$1.79	$1,091	$47
Natural Gas -10%	$48.06	$1.31	$997	($47)

Income taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards.

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that our net deferred tax assets will be utilized prior to their expiration. A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at June 30, 2021, driven primarily by impairments of evaluated oil and gas properties recognized beginning in the second quarter of 2020 and continuing through the fourth quarter of 2020, which limits the ability to consider other subjective evidence such as our potential for future growth. Since the second quarter of 2020, based on the evaluation of the evidence available, we concluded that it is more likely than not that the net deferred tax assets will not be realized. As a result, we recorded a valuation allowance, reducing the net deferred tax assets as of June 30, 2021 to zero.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income. As long as we continue to conclude that the valuation allowance against our net deferred tax assets is necessary, we will have no significant deferred income tax expense or benefit. See "Note 9 - Income Taxes" for additional discussion.

Recently Adopted and Recently Issued Accounting Pronouncements

See "Note 1 - Description of Business and Basis of Presentation" for discussion.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer credit risk. We mitigate these risks through a program of risk management including the use of commodity derivative instruments.

Commodity price risk

Our revenues are derived from the sale of our oil, natural gas and NGL production. The prices for oil, natural gas and NGLs remain volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, government actions, economic conditions, and weather conditions.

The following table sets forth oil, natural gas and NGL revenues for the three months ended June 30, 2021 as well as the impact on the oil, natural gas and NGL revenues assuming a 10% increase or decrease in our average realized sales prices for oil, natural gas and NGLs, excluding the impact of commodity derivative settlements:

	Three Months Ended June 30, 2021			
	Oil	**Natural Gas**	**NGLs**	**Total**
	(In thousands)			
Revenues	$333,442	$24,080	$36,625	$394,147
Impact of a 10% fluctuation in average realized prices	$33,344	$2,408	$3,663	$39,415

	Six Months Ended June 30, 2021			
	Oil	**Natural Gas**	**NGLs**	**Total**
	(In thousands)			
Revenues	$600,487	$48,300	$65,982	$714,769
Impact of a 10% fluctuation in average realized prices	$60,049	$4,830	$6,598	$71,477

From time to time, we enter into derivative financial instruments to manage oil, natural gas and NGL price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes we hedge through use of our derivative instruments varies from period to period. Generally our objective is to hedge approximately 60% of our anticipated internally forecasted production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices.

As of June 30, 2021, for the remainder of 2021, we had6,994,775 Bbls of fixed price oil hedges across NYMEX WTI, ICE Brent and Argus WTI-Houston benchmarks. We also had 1,504,400 Bbls of WTI Midland-Cushing oil basis hedges. Additionally, for the remainder of 2021, we had 10,981,000 MMBtus of fixed price NYMEX natural gas hedges and 8,280,000 MMBtus of Waha natural gas basis hedges. See “Note 7 - Derivative Instruments and Hedging Activities” for a description of our outstanding derivative contracts as of June 30, 2021.

We may utilize fixed price swaps, which reduce our exposure to decreases in commodity prices, but limits the benefit we might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales.

We also may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counterparty to the collar pays the difference to us, and if the price rises above the ceiling, the counterparty receives the difference from us. Additionally, we may sell put options at a price lower than the floor price in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices. In a three-way collar, to the extent that realized prices are below the floor price of the sold put option (or above the ceiling price of the sold call option), our net realized benefit from the three-way collar will be reduced on a dollar-for-dollar basis.

We may purchase put options, which reduce our exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to us.

We enter into these various agreements from time to time to reduce the effects of volatile oil, natural gas and NGL prices and do not enter into derivative transactions for speculative or trading purposes. Presently, none of our derivative positions are designated as hedges for accounting purposes.

Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. As of June 30, 2021, we had $875.0 million outstanding under the Credit Facility with a weighted average interest rate of 2.61%. An increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our annual interest expense of approximately $8.8 million, based on the balance outstanding as of June 30, 2021. See “Note 6 - Borrowings” for more information on our Credit Facility.

Counterparty and customer credit risk

Our principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

We market our oil, natural gas and NGL production to energy marketing companies and are subject to credit risk due to the concentration of our oil, natural gas and NGL receivables with several significant customers. The inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security. At June 30, 2021, our total receivables from the sale of our oil, natural gas and NGL production were approximately $148.7 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. We generally have the right to withhold future revenue distributions to recover past due receivables from joint interest owners. The allowance for credit losses related to our joint interest receivables is immaterial. At June 30, 2021, our joint interest receivables were approximately $12.9 million.

Our oil, natural gas and NGL commodity derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. All of the counterparties of our commodity derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional commodity derivative instruments with these or other lenders under our Credit Facility, representing institutions with investment grade ratings. We have existing ISDA Agreements with our commodity derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of offset upon the occurrence of defined acts of default by either us or a counterparty to a commodity derivative, whereby the party not in default may offset all commodity derivative liabilities owed to the defaulting party against all commodity derivative asset receivables from the defaulting party. At June 30, 2021, we had a net commodity derivative liability position of $315.5 million.

Item 4. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our management, with the participation of the Chief Executive Officer and Chief Financial Officer, performed an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of June 30, 2021.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the second quarter of 2021 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

We are not currently a party to, nor is our property currently subject to, any material legal proceedings other than ordinary routine litigation incidental to the business, and we are not aware of any such proceedings contemplated by governmental authorities.

Item 1A. Risk Factors

There have been no material changes to the risk factors set forth under the heading "Part I, Item 1A. Risk Factors" included in our 2020 Annual Report on Form 10-K. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The following exhibits are filed as part of this Form 10-Q.

Exhibit Number		Description	Incorporated by reference (File No. 001-14039, unless otherwise indicated) Form	Exhibit	Filing Date
3.1		Certificate of Incorporation of the Company, as amended through May 12, 2016	10-Q	3.1	11/03/2016
3.2		Certificate of Amendment to the Certificate of Incorporation of Callon, effective December 20, 2019	8-K	3.1	11/20/2019
3.3		Certificate of Amendment to the Certificate of Incorporation of Callon, effective August 7, 2020	8-K	3.1	8/07/2020
3.4		Certificate of Amendment to the Certificate of Incorporation of Callon, effective May 14, 2021	8-K	3.1	5/14/2021
3.5		Amended and Restated Bylaws of the Company	10-K	3.2	2/27/2019
4.1		Indenture, dated as of July 6, 2021, by and among the Company, Callon Petroleum Operating Company, Callon (Eagle Ford) LLC, Callon (Niobrara) LLC, Callon (Permian) LLC, Callon (Permian) Minerals LLC, Callon (Utica) LLC, Callon Marcellus Holding, Inc. and U.S. Bank National Association, as trustee.	8-K	4.1	7/7/2021
10.1	(c)	Form of Callon Petroleum Company Restricted Stock Unit Agreement, adopted on March 12, 2021 under the 2020 Omnibus Incentive Plan.	8-K	10.1	4/16/2021
10.2	(c)	Form of Callon Petroleum Company Cash Performance Unit Agreement, adopted on March 12, 2021 under the 2020 Omnibus Incentive Plan.	8-K	10.2	4/16/2021
10.3	(c)	Form of Change in Control Severance Compensation Agreement, dated as of April 16, 2021, by and between Callon Petroleum Company and its executive officers.	8-K	10.3	4/16/2021
10.4	(c)	Change in Control Severance Compensation Agreement, dated as of April 16, 2021, by and between Callon Petroleum Company and Joseph C. Gatto, Jr.	8-K	10.4	4/16/2021
10.5	(c)	First Amendment to Callon Petroleum Company 2020 Omnibus Incentive Plan.	8-K	10.5	4/16/2021
10.6		Fourth Amendment, dated May 3, 2021, to the Credit Agreement by and between Callon Petroleum Company and JP Morgan Chase Bank N.A., as administrative agent, and the lender parties thereto.	10-Q	10.6	5/6/2021
10.7		Purchase Agreement, dated as of June 21, 2021, among Callon Petroleum Company, the Guarantors and BofA Securities, Inc., as representative of the several initial purchasers.	8-K	10.1	6/22/2021
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)			
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)			
32.1	(b)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)			
101.INS	(a)	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	(a)	Inline XBRL Taxonomy Extension Schema Document			
101.CAL	(a)	Inline XBRL Taxonomy Extension Calculation Linkbase Document.			
101.DEF	(a)	Inline XBRL Taxonomy Extension Definition Linkbase Document.			
101.LAB	(a)	Inline XBRL Taxonomy Extension Label Linkbase Document.			
101.PRE	(a)	Inline XBRL Taxonomy Extension Presentation Linkbase Document.			
104	(a)	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			

(a) Filed herewith.

(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act, except to the extent that the registrant specifically incorporates it by reference.

(c) Indicates management compensatory plan, contract, or arrangement.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Callon Petroleum Company

Signature	Title	Date
/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr.	President and Chief Executive Officer	August 4, 2021
/s/ Kevin Haggard Kevin Haggard	Senior Vice President and Chief Financial Officer	August 4, 2021

Exhibit 31.2

CERTIFICATIONS

I, Kevin Haggard, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2021

/s/ Kevin Haggard
Kevin Haggard
Senior Vice President and Chief Financial Officer
(Principal financial officer)

Exhibit 31.1

CERTIFICATIONS

I, Joseph C. Gatto, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 4, 2021

/s/ Joseph C. Gatto, Jr.
Joseph C. Gatto, Jr.
President and Chief Executive Officer
(Principal executive officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Quarterly Report on Form 10-Q of Callon Petroleum Company for the quarterly period ended June 30, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacities and on the dates indicated below, each hereby certify pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that the Report fully complies with requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	August 4, 2021	/s/ Joseph C. Gatto, Jr. Joseph C. Gatto, Jr. (Principal executive officer)
Date:	August 4, 2021	/s/ Kevin Haggard Kevin Haggard (Principal financial officer)

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.